COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF LOUISVILLE GAS AND	)	
ELECTRIC COMPANY FOR APPROVAL OF	)	CASE NO. 98-426
AN ALTERNATIVE METHOD OF REGULATION	)	
OF ITS RATES AND SERVICE	)	

TESTIMONY OF

MARK NEWTON LOWRY
VICE PRESIDENT - REGULATORY STRATEGY
CHRISTENSEN ASSOCIATES

Q. Please state your name and business address.

A. My name is Mark Newton Lowry. My business address is 4610 University Avenue, Madison, WI 53705.

Q. What is your position?

A. I am Vice President of Regulatory Strategy at Christensen Associates.

Q. Please describe your work experience.

I joined Christensen Associates as a Senior Economist in 1983 and have been a Vice President of the company for five years. The Regulatory Strategy group that I direct advises clients on performance-based regulation ("PBR"), statistical benchmarking, restructuring and other policy issues facing energy utilities. I supervise the group's empirical work, design PBR plans, and give expert witness testimony. Before joining Christensen Associates, I was an Assistant Professor of Mineral Economics at the Pennsylvania State University. My academic research and teaching there stressed the use of mathematical theory and advanced empirical research techniques in market analysis.

My B.A. in Latin-American Studies and my Ph.D. in Agricultural and Resource Economics are both from the University of Wisconsin - Madison. I have served as an editor for several scholarly journals and have an extensive record of professional publications and public appearances. My vita is attached to this testimony as Appendix A.

Q. What is the purpose of your testimony?

A. My testimony addresses the theory and current practice of PBR, explains why conventional regulation is less appropriate than PBR, presents an economic analysis that demonstrates superior performance for Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively referred to as "the Companies"), and supports the fuel price data used in the fuel cost recovery component of the proposed PBR plan.

Regulatory Framework

Q. Please provide an overview of the fundamental principles of regulation.

A. Economists believe that competition is generally the most desirable form of market organization. While extolling the benefits of competition, they recognize that the special economies in the provision of some electric services make it rational to provide them through utilities. Regulation of utilities provides an effective surrogate for competition to the extent that competitive outcomes are realized.

The use of regulation to promote competitive market outcomes may be called the competitive market paradigm. Dr. James C. Bonbright puts it this way:

> Regulation, it is said, is a substitute for competition. Hence its objective should be to compel a regulated enterprise, despite its possession of complete or partial monopoly, to charge rates approximating those which it would charge if free from regulation but subject to the market forces of competition. In short, regulation should be not only a substitute for competition, but a closely imitative substitute.[1]

Under competition, prices reflect supply and demand conditions at the industry level, and not the actions of individual market participants. Suppliers therefore keep all of the after-tax dollars from their efforts to slow unit cost growth. This creates strong incentives to contain costs and develop market-responsive services. The growth in industry unit cost is thereby slowed. In the long run, competition shares the benefits of slower unit cost growth with customers in the form of slower price growth. Competitive markets thus promote efficiency in supplier operations and share these benefits with customers.

The competitive market paradigm sometimes can be achieved by a restructuring that creates actual competition and permits the decontrol of traditionally-regulated services. This is so where special economies are no longer great enough to warrant monopoly service provision. Restructuring initiatives are well underway in several traditionally-regulated industries, including

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[1] James C. Bonbright, Principles of Public Utility Rates (1961, Columbia U. Press), p. 93.

aviation, interstate gas supply, power supply, railroads, telecommunications, and trucking. However, the special economies in monopoly provision of some electric services -- particularly distribution and transmission -- make complete decontrol impractical.

Despite the fact that regulation should yield results similar to those of competition, it rarely does. Simply put, utilities typically do not offer the market-responsive services or the generally low prices that we would expect from competitive market suppliers. The need for a regulatory framework that more closely and accurately reflects the competitive marketplace is therefore highly desirable, and especially compelling during the current transition from a fully-regulated electric power industry to a more freely competitive market. Regulators should consider methods of regulation that produce economic pressures similar to those prevalent in competitive markets and that share the resulting benefits with customers.

Q. **Please discuss why conventional, cost-of-service rate with its frequent rate cases regulation does not fulfill the competitive market paradigm.**

A. This method of regulation generally does not achieve the maximum possible efficiency from utility operations. In the opinion of many regulatory economists, an important aspect of the problem is the high cost that must be incurred for regulators to identify rate and service offerings that would prevail under competition. It is difficult even for experienced utility managers to recognize the best cost containment and marketing practices. Substantial data exchange, processing, and analysis would be required to identify competitive market outcomes. These investigations would be costly.

Measures understandably are taken by the regulatory community to contain regulatory costs. One is to control earnings. A second is to restrict utility operations that complicate regulation. A third is to extend the period between rate cases. These measures reduce regulatory cost, but some also reduce utility efficiency.

Setting rates to control a utility's earnings makes the rates reflect the utility's unit cost and not a competitive market standard.

Restrictions on utility operations also can reduce efficiency. For example, limited service offerings and inflexible rates hamper the utility's ability to satisfy market demands. Some utility services then may not be provided that have a value exceeding their cost of provision. The efficiency consequences are more acute in markets for services where demand is sensitive to service terms. For electric utilities, these markets include those for service to businesses with power-intensive technologies, economically-marginal businesses, and expanding businesses.

An extension of the length of the period between rate cases is one economy measure available under traditional regulation that can enhance utility efficiency. As the length increases, utilities keep more of the benefits of efforts to slow unit cost growth. This strengthens performance incentives that have benefitted customers. Unfortunately, energy utilities, like businesses in most sectors of the economy, cannot survive in the long run without occasional price increases to help offset the earnings impact of input price growth.

Q. Can PBR do a better job of simulating a competitive market paradigm?

A. Yes. PBR does a better job of realizing competitive market outcomes because it bases regulation less on earnings controls and more on external performance standards. It accomplishes this in part by reliance on data that are external in the sense of being insensitive to the actions of utility managers. One example is data on the prices paid for production inputs by other utilities. Another is the performance standards established by the utility before the start of PBR.

Reliance on external performance standards also is fostered by automatic rate adjustment mechanisms that are established in advance of their operation. These mechanisms reduce the frequency and scope of regulatory proceedings. They also discourage changes in the regulatory framework that bring rates closer to a company's unit cost and thereby transfer to customers the benefits of special performance improvements initiatives.

To the extent that rate adjustments are based on a combination of external data and automatic adjustment mechanisms, utilities can hope to keep the benefits of efforts to improve performance, like competitive market suppliers. Incentives to improve the efficiency of utility operations then are increased.

PBR plans can be designed to share the benefits of improved performance with customers. For example, rate trajectories can be proposed in advance that offer customers good value. PBR therefore has the potential to create a situation in which both utility shareholders and customers benefit.

Q. Please explain why PBR is especially useful in the transition of the electric power industry to retail competition.

A. I believe that there are three reasons why PBR has special advantages in this period of power industry restructuring. One is its value in keeping the rates and service of utilities remaining under regulation competitive with those across the country. The attractive terms of service that PBR makes possible are always beneficial. Businesses, for example, benefit from low power prices and market-responsive service packages both directly and indirectly, through their effect on the cost of living and local wages. The special challenge for regulators who do not choose competition is avoiding erosion in the relative attractiveness of the state's power service terms.

Retail competition is now underway in several states and is scheduled for many more. Included are large industrialized states like Pennsylvania and New York. The share of the nation's power consumers who are certain to have competitive options within five years is therefore appreciable. I believe that competition in power supply eventually will reach the great majority of the nation's retail customers.

Where competition is allowed, the terms of power supply service will improve steadily. Gains in many cases will be dramatic in the long run since competition is occurring first in states where the industry is least efficient.

PBR is more capable of generating competitive market outcomes until such time as a Commission decides that retail power supply competition is the right thing to do. The fact that a Commission may never choose competition actually supports the PBR option.

Q. What is the second reason why PBR is especially useful in transitioning industries?

A. The second reason is that conventional regulation will induce a decline in the efficiency of companies subject to it relative to competitive market operators. Competition will profoundly strengthen the performance incentives of power suppliers where it occurs. They will be stimulated by these incentives to adopt state-of-the-art cost containment and marketing techniques. The result will be significant human capital formation.

Companies subject to conventional regulation will experience weaker performance incentives and greater operating restrictions that impair human capital formation. This compromises their chances for survival as major, locally-based enterprises. Consider by way of example a company with five years of successful power generation and marketing experience in the newly competitive Pennsylvania market. The know how gleaned from this experience might permit it to pay a premium for a Kentucky-based utility just beginning restructuring and coming off of five years of conventional regulation.

Q. What is the third reason why PBR is especially useful in transitioning industries?

A. The third reason is that PBR can help mitigate cost allocation concerns during the transition period. Restructurings in some states feature a phased introduction of competition. Utilities then may be compelled to serve competitive and non-competitive retail markets simultaneously using the same facilities. The issue then arises of the appropriate allocation of cost between competitive and non-competitive markets. PBR mitigates these cost allocation concerns to the extent that price restrictions reflect external performance standards rather than the utility's cost.

Q. Please characterize the current regulatory systems of KU and LG&E.

A. Both Companies have operated for many years without a rate case that sets their revenue requirement equal to their cost. The last KU rate case was in 1982-83. The last LG&E rate case was in 1990. In the absence of rate cases, the base rates of each Company have not changed. Adjustments for recovery of changes in generation fuel and certain power purchase expenses are set by fuel adjustment clause mechanisms. Adjustments for recovery of environmental-related costs are set by an environmental surcharge.

Under the terms of the recent merger agreement, the Companies have committed to not increase base rates for another five years. A merger surcredit will reduce rates over this period to share the estimated benefits from the merger with customers.

Q. **How have the Companies continued operations with base rates unchanged over such lengthy time periods?**

A. Demand growth in service territories of modest size has allowed the Companies to realize economies of scale. Inflation in the prices of base rate inputs has been slow. These conditions have given the Companies a chance to continue operation without base rate increases if they could aggressively contain cost growth.

Q. **Please assess the incentive for performance improvement provided by this regulatory framework.**

A. The Commission wisely has elected not to require the Companies to make rate case filings in this environment. This approach to regulation by Kentucky's Commission -- which differs from conventional rate regulation with its frequent rate cases -- has generated commendable performance incentives for both Companies. Efforts to improve efficiency in the use of base rate inputs have reduced the likelihood of a rate case by reducing the need for base rate increases. Managers have had the opportunity to operate for several years without a rate case. They thus have had the prospect of keeping the benefits of performance improvements for an extended period. Efforts to lower fuel costs and maintain or improve service quality also have reduced chances for a rate case by strengthening customer satisfaction. This plainly has been a favorable environment for the development of superior utility performers in the Commonwealth.

Q. Have customers benefitted from this situation?

A. Very definitely. With inflation in the prices of the economy's final goods and services typically running between 2-3% annually, the Companies' base rates have declined substantially in real terms. The rates for fuel cost recovery actually have declined in nominal terms. Over time, these developments have produced significant savings for each Company's customers. Frequent rate cases, with their attendant diminution of performance incentives, would not, in my opinion, have generated such favorable results.

Q. What is your conclusion regarding the best alternative approach to the regulation of utility services in Kentucky?

A. Conventional rate regulation with its frequent rate cases, discourages utilities from turning in their best performance, to the detriment of customers. Kentucky's regulators have wisely chosen a different path that focuses on results for customers , rather than tight earnings controls. PBR merits consideration as an enhancement to the regulatory framework of the Commonwealth.

Performance Appraisal

Q. Do you have quantitative results to support your appraisal that LG&E and KU are superior performers?

A. Yes. We performed a number of rate comparisons for the Companies using Federal Energy Regulatory Commission ("FERC") Form 1 data. The survey considered the rates for a national aggregate of major investor-owned electric utilities ("IOUs") and for an aggregate of major IOUs that are members of the East Central Area Reliability Council ("ECAR"). ECAR members serve the area comprising Michigan, Indiana, Ohio, West Virginia, Kentucky, and adjacent portions of Pennsylvania, Maryland, and Virginia.

Two rate comparison measures were calculated: system average retail rates (total retail revenue/total retail sales volume) and a retail rate index. The rate index that we employed was a weighted average of the revenue/MWh for three retail service classes: residential, industrial, and other retail. The shares of each service class in total retail revenue were the weights. We believe this to be the more accurate rate comparison measure since it controls for differences between companies and over time in the mix of services provided.

The results of this exercise are presented in Exhibit MNL-1. It can be seen that, from 1985 to 1996, the retail rate indexes of LG&E and KU fell by an average of 1.0% and 1.7%, respectively, in nominal terms each year. The rates of the ECAR fell at average annual rates of only 0.3%; and national IOU aggregates did not change at all (0.0%) over the same period. In other words, rates fell more rapidly than those of the typical utility despite less frequent rate cases.

Q. Granted that the rate *trends* were favorable to Company customers, how have their rate *levels* compared to those of other utilities recently?

A. Using retail rate indexes, we found that, in 1996, the rates of LG&E were a substantial 21% below those of the national aggregate on average. Those of KU were fully 35% below the national aggregate's rate level. In contrast, the retail rates of the ECAR aggregate were only 13% below those of the national aggregate. Similar results can be seen using system average rates as the comparison measure.

Q. Both Companies serve a region with important operating advantages, including low prices for generation fuels. Have you considered whether the low prices the utilities offer reflect operating efficiencies in addition to operating advantages?

A. Yes. I have developed a model of the cost of bundled power services like those offered by Companies to retail customers. The model is based on economic theory, industry data, and sophisticated statistical techniques. The average total cost incurred for power services by each Company over the 1992-96 period was compared to the cost predicted by the model. The results show KU to rank fourth and LG&E to rank twelfth out of 104 sampled utilities. This clearly suggests that the cost performances of both utilities were significantly superior to the industry standard in recent years.

Q. Please describe this work in more detail.

A. We developed a mathematical model of the relationship between the cost incurred by a company for electric utility services and an array of business conditions in its service territory. The parameters of the model, which quantify this relationship, were estimated statistically using well-established techniques and data on the historical costs of U.S. investor-owned electric utilities and the business conditions they face. The performances of LG&E and KU were evaluated by comparing their electric service costs to those predicted by the model given the business conditions in each company's service territory.

The study employed a cost model of translog form. This form is widely-used in utility cost research. The estimated parameters of the cost model are consistent with economic theory and reasonable in magnitude. A report on the cost performance research is presented as Exhibit MNL-2 and entitled "An Econometric Appraisal of the Cost Performance of LG&E and Kentucky Utilities."

Q. **What data were used in the study?**

A. The primary source was a set of FERC Form 1 data for 104 electric utilities for the years 1992-96. Data also were drawn from respected and publicly-available private sources such as Whitman, Reguardt and Associates.

Q. **What business conditions were found to be important determinants of electric utility cost?**

A. The most important cost drivers were found to be the prices of fuel, labor, capital services and other electric utility inputs, and two measures of workload: the power sales volume, and the number of electric customers served. We also controlled for important differences across companies concerning state policies regarding demand side management and required power purchases.

Q. **Why is your research method preferable to others that might be employed for cost performance evaluation?**

A. Four advantages of the methodology are salient. First, the choice of total cost as the performance variable permits us to draw on established economic theory to identify appropriate business condition variables for the model. It also provides expectations about the cost impact of business conditions. This helps us to assess the reasonableness of model parameters. A second advantage of the method is that total cost is a comprehensive performance variable and thus addresses the "bottom line" concern of ratepayers: the overall efficiency of the Companies' electric operations.

A third advantage of the approach is that econometric results can be used to test the statistical significance of any discrepancies between the Companies' actual costs and the designated cost standard. This is important since a model that does a poor job of explaining historical relationships between local business conditions and utility cost cannot provide much help in discerning superior performance. With our approach, only some companies with actual cost below predicted cost are deemed significantly superior.

Finally, an econometric approach to cost performance evaluation is easier to tailor to the circumstances facing a specific utility than a peer group approach. It is difficult to choose a peer group that faces business conditions that are highly similar to those of the subject utility. Econometric methods permit us to use data from utilities in diverse circumstances to quantify the effects of business conditions on cost in the general case. The utility's actual cost is then evaluated using the exact business conditions that it faces.

Q. What conclusions do you draw from your rate and cost studies?

A. I conclude that, during the period in which the Companies have operated with infrequent rate cases, their prices have improved relative to those of the region and nation, and; they have been significantly superior cost performers. These results are consistent with the view that a regulatory framework focused on results rather than earnings can induce superior performance and share benefits with customers.

Review of PBR Options

Q. What review of PBR options did you perform?

A. We presented the Companies with the basic principles for the design of PBR plans, detailed a range of PBR options, and noted major precedents for each option. Our review also considered the regulatory commitments that the Companies have made. These include the base rate cap and the merger surcredit.

Q. What were the highlights of the review?

A. The review showed that the use of PBR mechanisms is well established for investor-owned utilities and is growing rapidly in the United States and foreign countries. PBR mechanisms have been approved by the Federal Communications Commission and the Federal Energy Regulatory Commission, and by at least 32 different state commissions for regulating telecommunications companies, gas distribution companies, electric companies, gas pipeline companies and oil pipeline companies. We recommended that the Companies give careful consideration to two kinds of PBR mechanisms: benchmark incentives and price caps. These mechanisms are of three basic kinds. Benchmark incentives compare a utility's operations to an external benchmark and adjust rates to share with customers the benefits of measured performance improvements. The benchmarks draw their external character from data for other utilities or from historical data for the subject utilities. Benchmark incentives are especially common in the regulation of service quality and gas supply. The Kentucky gas supply PBR plans of Columbia Gas and LG&E are examples. In the electric power industry, they also have been used in several states to create incentives for better power plant performance.

Another major approach to PBR is price cap regulation. Under a price cap plan, the growth in a utility's prices is limited by a price cap index ("PCI"). As practiced in the United States, the PCI is designed to simulate competition by tracking the unit cost trend of the utility industry. Price cap plans typically have a duration of five years and often continue thereafter without a cost of service rate true-up. The first large scale price cap plan, that for U.S.

railroads, was established in the early 1980's under the terms of the Staggers Rail Act.

Q. You have stated that PBR is especially appropriate for utility industries in transition to competition. Is PBR especially common in such industries?

A. Very much so. The case of price caps and other forms of rate indexing is illustrative. Railroads were subject to extensive competition from barge lines, truckers and, other railroads. Rate indexing spread in the late 1980's to interstate telephone services. AT&T faced competition from Sprint and other interexchange carriers (IXCs) while local phone companies faced interstate competition from MFS and other IXC access providers. Rate indexing is now common as well in the regulation of local telephone services where competition is growing under the terms of the Telecommunications Act of 1996, and other policy initiatives, where competition was also pervasive. The FERC applies rate indexing to interstate oil pipeline services. In the electric utility industry, indexing has been approved for unbundled power distribution in Great Britain, Australia, and two of the first American restructuring states: California and Rhode Island.

Q. Based on your review, what PBR measures did you recommend?

A. We advised the Companies that their current regulatory commitments involve an impressive combination of customer benefits and strong performance incentives. Improvements to the regulatory framework nonetheless are warranted. We helped in the development of benchmarking plans that strengthen incentives for fuel price containment and quality service, and share benefits of better performance with customers.

Q. Please summarize the PBR plans that the Companies are presenting in this proceeding.

A. The plans of the two companies are essentially the same. Each has five components. The first component is a performance-based fuel cost recovery ("FCR") mechanism. The second component covers merger dispatch savings. The third component covers generation performance improvements. The fourth component is a package of benchmark incentives for service quality. The fifth component is a provision for market-determined rates for new and optional utility service tariffs. This component is premised on the continuing recourse of optional tariff customers to the Companies' standard tariff offerings.

Q. Do the regulatory proposals of the Companies satisfy your standards for an effective PBR plan?

A. Very definitely. The proposed framework provides strong performance incentives and removes unnecessary restrictions on the development of market-responsive service offerings. This helps Kentucky's major investor-owned electric utilities maintain the competitive edge they need to succeed in a restructuring industry. The terms also provide for a continuation of the favorable rate levels and rate stability that customers of the companies have long enjoyed. In summary, the proposals result in a very beneficial situation for the shareholders and customers of LG&E and KU.

Fuel Cost Recovery

Q. Please summarize the Companies' incentive fuel proposals.

A. The proposals are quite similar, so I will speak of them here as one. The basic idea is to make adjustments in charges for power generation fuel based on a comparison of trends in delivered fuel prices paid by the Companies to measured regional trends in delivered fuel prices. This should create an incentive for the Companies to continue to bargain hard on price terms with fuel suppliers and transporters (e.g., railroad, truck, and barge line operators), and to manage fuel logistics efficiently.

Q. Do you believe that these activities previously were not well-managed?

A. Not at all. I believe, however, that it is wise to provide the right incentives for future fuel procurement activities.

Q. What criteria should be used to select fuel price data for this PBR mechanism?

A. I believe that the data should be credible, timely, and accurate. Credibility is maintained when data are provided by government agencies and reporting is mandatory. Since fuel prices are volatile, it is desirable that rates be adjusted in a timely manner for fuel price changes.

Data should reflect accurately trends in the prices paid to procure fuel in the field and to transport fuel to the power plant. Indexes of coal price trends should, additionally, control for changes in the quality of coal that is traded. The quality attribute of coal that most greatly affects its price trend today is its sulfur content. This is due in part to the Clean Air Act and other laws and regulations restricting sulfur emissions. Substitution of low-sulfur compliance coal for high-sulfur coal then would create an upward aggregation bias if we were to measure coal price growth using the average delivered cost of both coal types.

Q. What coal data sources did you evaluate using these criteria?

A. We examined several sources of coal price data, including: Bureau of Labor Statistics Producer Price Indexes for the mine price of coal; U.S. Energy Information Administration Form 7A mine price data; Data Resources International coal field spot price data; and FERC Form 423 data on the cost and quality of steam generation fuels delivered to electric utilities. We also examined some alternative indexes of coal transportation prices.

Q. What coal price data source finally was chosen?

A. The coal price data chosen were from the FERC Form 423 spot price data. This source gets high marks using all of the stated criteria. It is timely since it is gathered and released monthly. It is credible since it is filed with the Federal Government and reporting is mandatory. It is accurate since the quality of all coal shipments is reported. It is then possible to construct indexes of coals with different quality attributes. The prices actually used are those for the reporting utilities in a five-state region that is centered on Kentucky. The five states are: Indiana, Ohio, West Virginia, Tennessee, and Kentucky. The use of regional price data helps to simulate competition since these same prices are important determinations of power prices in the region.

Q. **What data source was chosen for the gas price subindex?**

A. The gas price subindex for both companies is based on the *Natural Gas Week* spot prices at CNG Transmission Co. North and at CNG Transmission Co. South.

Q. **Why use spot prices on the CNG system for the gas price subindex?**

A. CNG Transmission is in the business of moving gas from the southern Midwest and central Appalachia to the northeast. It relies on Tennessee, Texas Eastern, and other carriers for all gas deliveries made from the Gulf Coast to its facilities. CNG North and CNG South are the major transfer points for gas that CNG ships and have become locations of major spot trades in the region. Both are located close to the service territory of KU and LG&E.

Q. **Can you summarize your comments on the proposed fuel price data.**

A. Yes. I believe that it is appropriate to base the fuel cost recovery mechanism on regional fuel price data. The specific price series chosen are of good quality and are the best available for this application.

Q. **Does this conclude your testimony?**

A. Yes it does.

VERIFICATION

STATE OF WISCONSIN)
) SS.
COUNTY OF DANE)

MARK NEWTON LOWRY, being first duly sworn, deposes and states:

That he has read the foregoing testimony and knows the matters contained therein; that said matters are true and correct to the best of his knowledge and belief, except as to those matters stated on information and belief, and as to those matters, he believes them to be true.

Mark Newton Lowry

Mark Newton Lowry

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 5th day of October, 1998.

(SEAL)

Melinda J. Jensen

Notary Public

My Commission Expires:

August 6, 2000

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APPENDIX A
ABBREVIATED CURRICULUM VITAE

Mark Newton Lowry is a Vice President of Christensen Associates, an economic consulting firm in Madison, WI, where he directs the company's regulatory strategy group. His specialities include incentive regulation for electric utilities, gas distribution utilities, and interstate gas transmission utilities; energy utility restructuring; energy market analysis; and utility rate design.

In addition to Louisville Gas and Electric Company and Kentucky Utilities Company, Dr. Lowry has advised numerous energy utilities on rate and service issues, including incentive regulation. Those energy utilities include: AEPCO; Atlanta Gas Light; Boston Gas; Central Maine Power; City of St. Cloud, MN; Commonwealth Energy System; Delmarva Power; Hawaiian Electric Company; Iowa Power; New England Electric Power Service; Niagra Mohawk Power; NMGas; Northern States Power-Wisconsin; Pacific Gas & Electric; Public Service Co. of New Mexico; Public Service Electric & Gas; San Diego Gas & Electric; Southern California Edison; Southern California Gas; Southern Company Services; and Southern Natural Gas. In addition, Dr. Lowry has advised the following international companies: Distribution companies of Victoria (Australia); Alberta Power (Canada); BC Gas (Canada); Comision de Regulacion de Energia y Gas (Colombia); Tokyo Electric Power (Japan); and Comision Reguladora de Energia (Mexico). Dr. Lowry also has advised several energy institutes, including

Edison Electric Institute; Electric Power Research Institute; and New England Fuel Institute.

As part of the major consulting projects Dr. Lowry undertook on behalf of several of the above-named energy utilities, he provided the following testimony:

Gas and Power Distribution PBR Research and Testimony for a California Energy Utility.
(San Diego Gas & Electric, 1997-98)

PBR Plan Design, Statistical Benchmarking, and Testimony for a Southeast Gas Distributor.
(Atlanta Gas Light, 1997)

Statistical Benchmarking and Testimony for a California Electric Utility.
(Pacific Gas & Electric, 1997)

PBR Testimony for a Canadian Gas Distributor.
(BC Gas, 1997)

Testimony on Price Cap Regulation for Power Distribution.
(Commonwealth Energy System, 1996)

Productivity and Cost Performance Research and Supporting Testimony for a Price Cap Filing.
(Boston Gas, 1996)

Advanced Benchmarking Techniques for a Natural Gas Distributor and Supporting Testimony.
(Boston Gas, 1996)

Productivity Testimony in Support of a Price Cap Plan.
(NMGas, 1995)

Testimony in Support of a Price Cap Plan.
(Southern California Gas, 1995)

Testimony in Support of a Price Cap Plan.
(Central Maine Power, 1994)

Dr. Lowry also has given numerous professional presentations, has served as an editor for several professional journals, and is the author or co-author of several publications, including:

Price Cap Regulation for Power Distribution (with Lawrence Kaufmann) (Washington: Edison Electric Institute, forthcoming).

A Price Cap Designers Handbook (with Lawrence Kaufmann) (Washington: Edison Electric Institute, 1995).

Performance-Based Regulation of U.S. Electric Utilities: The State of the Art and Directions for Further Research (Palo Alto: Electric Power Research Institute, December 1995).

The Treatment of Z Factors in Price Cap Plans (with Lawrence Kaufmann), Applied Economics Letters 2 1995.

Gas Supply Cost Incentive Plans for Local Distribution Companies. Proceedings of the Eighth NARUC Biennial Regulatory Information Conference (Columbus: National Regulatory Research Institute, 1993).

Indexed Price Caps for U.S. Electric Utilities. The Electricity Journal, September-October 1991.

Review of Oil Prices, Market Response, and Contingency Planning, by George Horwich and David Leo Weimer, (Washington, American Enterprise Institute, 1984), Energy Journal 8(3) 1988.

Review of Energy, Foresight, and Strategy, Thomas Sargent, ed. (Baltimore: Resources for the Future, 1985), Energy Journal 6(4) 1986.

Dr. Lowry holds a Ph.D. in Agricultural and Resource Economics from the University of Wisconsin-Madison.

Exhibit MNL-1

SUMMARY OF RETAIL PRICE RESULTS

	LGE		KU		ECAR		Nation	
	1985-96	96 Level	1985-96	96 Level	1985-96	96 Level	1985-96	96 Level
Average Revenue (Revenue/kWh)								
Residential	-0.7%	0.68	-1.6%	0.52	0.9%	0.90	1.2%	1.00
Industrial	-1.7%	0.75	-2.1%	0.71	-0.7%	0.94	-0.8%	1.00
Other Retail	-1.0%	0.92	-1.5%	0.75	-0.9%	0.82	-0.7%	1.00
System Average Retail Rate	-1.0%	0.80	-1.7%	0.65	-0.3%	0.85	0.0%	1.00
Retail Rate Index	-1.0%	0.79	-1.7%	0.65	-0.3%	0.87	0.0%	1.00

AN ECONOMETRIC APPRAISAL OF THE COST PERFORMANCE OF LG&E AND KENTUCKY UTILITIES

August 26, 1998

Dr. Mark Newton Lowry, *Vice President*
Dr. Mostafa Baladi, *Senior Economist*

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A. INTRODUCTION

Louisville Gas and Electric (LG&E) and Kentucky Utilities (KU) are proposing in this proceeding a framework for performance-based regulation. They have asked Laurits R. Christensen Associates (Christensen Associates) to appraise their recent cost performances as providers of electric services. The study was to draw on our extensive experience with cost modeling techniques and their application to electric utilities. This report presents the results of the study.

An econometric cost model was developed and used to predict the average annual cost of the electric utility services of the two companies from 1992 to 1996 given the business conditions that they faced. Their actual average costs were about 16% and 21%, respectively, below the model's predictions. A standard test revealed that the cost savings were statistically significant in both cases. The empirical evidence shows that both utilities were significantly superior cost performers during the sample period.

Accurate appraisal of a company's operations is challenging due to the scope and complexity of business conditions that it cannot control. In any industry, there are important differences between firms in the prices at which production inputs like labor and capital can be obtained, the character of local demand conditions, and in taxes and other policy conditions. Regulation of U.S. electric utilities creates special opportunities but also special challenges. Utilities have for many years been required to make detailed reports to federal agencies on their operations. This provides the data needed for rigorous benchmarking work. On the other hand, state and local laws and regulations greatly influence utility operations and have varied substantially between companies.

Our cost model explains the effect on the cost of electric service provision of an array of measurable business conditions. Model parameters were estimated by established statistical methods using data from 104 investor-owned American electric utilities. Cost performance was evaluated by comparing each utility's actual cost with that predicted by the model.

The parameter estimates for the major determinants of cost were in general statistically significant and plausible in sign and magnitude. Major cost drivers were found to be variables measuring the amount of work performed by a company; the prices it pays for energy, capital, and other production inputs; and electric utility policies such as required power purchases at high prices from unregulated generators.

One advantage of the general approach to performance measurement used in this study is the focus on the total cost of electric service as the performance indicator. Total cost is the ultimate basis for revenue and is thus an indicator tied directly to customer welfare. A focus on total cost also permits the use of the well-established economic theory of cost to select business condition variables. The resultant model is then anything but a "black box" that frustrates conscientious evaluation. Another advantage of the method is the ability to use results of the estimation procedure to create confidence intervals. These intervals constitute the full range of cost predictions that are consistent with the data. They are broader the less precise model predictions are believed to be. They therefore help to assess whether the difference of a company's actual cost from the model's prediction is significant.

This document presents results of our work. The plan for the report is as follows. *Section B* reviews our basic approach. *Section C* discussed the cost modeling methodology. There follows in *Section D* a discussion of the benchmarking results.

B. BASIC APPROACH

This section presents a concise and largely non-technical account of the benchmarking methods used in this study. A mathematical model called a cost function was developed to describe the effect on a company's total cost of electric utility service of business conditions in its service territory. Business conditions are defined as characteristics of a company's operating environment that may influence its activities but cannot be controlled by the company.

Economic theory can guide the selection of business condition variables. According to theory, the minimum total cost of an enterprise depends on the amount of work it performs and on the prices it pays for energy products, labor, and other goods and services used in production. Theory also provides some guidance regarding the nature of the relationship between business conditions and minimum total cost. For example, cost is apt to rise if there is inflation in input prices or more work is performed.

Here is a simple example of a cost model consistent with economic theory.

$$C_i = a_0 + a_1 \cdot V_i + a_2 \cdot W_i + u_i$$

For each company, i, C_i is the cost of service. It is a variable in the sense that its value may vary between companies and over time. The variable, V_i, is the company's delivery volume. It quantifies one dimension of the work that the company performs. The variable, W_i, is the wage rate that the company pays. The wage rate and the delivery volume are the measured business conditions in this simple model.

The parameters, a_0, a_1, and a_2, have values that are assumed to be constant during the sample period and the same for each sampled company. The values of a_1 and a_2 determine how a difference in the measured business conditions between companies should affect their expected costs of service. If the value of a_1 is positive, for instance, a company with a higher sales volume and the same wage rate as another company is expected to incur higher cost.

The variable, u_i, is called the error term. We assume that it is random. It is customary to assume a specific probability distribution for the error term that is determined by additional parameters, such as mean and variance. The error term is so-called because it is the model's error in predicting a company's actual cost. It reflects in part the exclusion from the model of business conditions that are difficult to measure. The error term also reflects the effect on a company's cost of the degree to which the company's operating efficiency differs from the industry norm. By isolating this portion of the error term utility performance can be measured.

The values of cost model parameters were estimated statistically. A branch of statistics called econometrics has established estimation procedures for the parameters of models used in economic research. Econometric estimates of the cost model parameters reflect the historical relationship between the costs incurred by companies in providing electric services and the measurable business conditions that they faced. For example, a positive estimate for parameter a_1 would reflect the fact that the cost reported by sampled utilities was typically higher the higher was their delivery volume.

A cost function fitted with econometric parameter estimates is called an econometric cost model. Fitted with the values of business condition variables faced by a company in a given year, a model of this kind can be used to predict its cost of service. Returning to our simple example, we might predict the cost of LG&E in period t as follows:

$$\hat{C}_{LGE,t} = \hat{a}_0 + \hat{a}_1 \cdot V_{LGE,t} + \hat{a}_2 \cdot W_{LGE,t}.$$

Here $\hat{C}_{LGE,t}$ is the predicted cost of LG&E in that period, $V_{LGE,t}$ was its actual delivery volume and $W_{LGE,t}$ was the wage rate that it paid. The $\hat{a}_0$, $\hat{a}_1$, and $\hat{a}_2$ terms are the econometric parameter estimates.

Information on the precision of cost model predictions can be used to assess the precision of such "point" predictions. For example, we can calculate a confidence interval consisting of the range of cost figures that is apt to encompass the true value at a certain confidence level. The point prediction lies at the center of this interval. The confidence interval may be viewed as the full range of cost figures that is consistent with the historical data. It is wider the larger and more varied is the sample and the less successful the model is in explaining the historical costs of sampled utilities.

Cost performance can be measured by comparing the cost that is actually incurred by a company with the model's cost prediction. The following comparison makes use of the point prediction of cost.

$$\textit{Estimated Cost Performance} = C_{LGE,t} - \hat{C}_{LGE,t}$$

Recall, however, that a range of cost figures are consistent with the data at a certain confidence level. We can then assess whether actual cost is bounded by the confidence interval. If it isn't, we may conclude that LG&E's actual cost differs significantly from the model's prediction. A cost significantly below the model's prediction, for example, would permit us to designate LG&E a significantly superior cost performer.

C. THE COST MODEL

Our econometric model was just noted to quantify the relationship between the total cost of a company's electric services and an array of measurable business conditions. This section provides some details of the cost model. Our definition of cost, the choice of business condition variables, and the data used in parameter estimation are all considered. Further details of the modeling work can be found in the work papers.

1. Data

Cost model parameters were estimated using data from a substantially comprehensive sample of major U.S. electric IOUs. The sample period for the regression work was 1992-96. The year 1996 is the latest for which final annual data are currently available. The primary source of the data was the Federal Energy Regulatory Commission (FERC) *Form 1*. This form is filed annually by all major U.S. electric IOUs, along with certain non-utility entities that are also jurisdictional to the FERC.[1] Selected *Form 1* data have been published regularly by the U.S. Energy Information Administration (EIA) in a series of publicly available documents that are currently entitled *Financial Statistics of Major US Investor-Owned Electric Utilities.*

All major U.S. electric IOUs which filed the FERC *Form 1* electronically in 1995 and which have reported the required data continuously since they achieved a "major" designation were considered for sample inclusion. In 1995, a total of 187 companies classified as major (179 utilities and 8 other entities) filed the *Form 1* electronically. To be included in the study companies were required, additionally, to have plausible data and be vertically integrated as determined by threshold levels of involvement in power generation, transmission, and distribution. One hundred and four companies met all of these standards. We believe that the data for these companies are the best available to perform rigorous research on the determinants of the cost of the bundled power services

[1] The selection criteria used in determining the major IOU classification is detailed in *Financial Statistics of Major US Investor-Owned Electric Utilities (1993)* EIA page 2.

commonly provided by U.S. utilities. The included companies are listed in Table 1. The sources for their data are listed in Table 2.

2. Defining Cost

Applicable total cost was calculated as the sum of total electric O&M expenses and electric capital service cost. Total electric O&M expenses are reported in FERC Form 1. The study used a service price approach to capital cost measurement that is based on the economic value of utility plant. Under this approach, the cost of capital is the product of the size of the capital stock and the price of capital services. This method has a solid basis in economic theory and is well established in the scholarly literature. It controls in a precise and standardized fashion for differences between utilities in the age of plant additions. Accordingly, there is no need for a "plant age" business condition variable. A detailed discussion of our capital cost measure can be found in the work papers.

Figure 1 shows the breakdown of total electric utility cost resulting from our computation procedure. Figures are reported for LG&E and Kentucky Utilities and a hypothetical company facing sample mean values for measured business conditions. The results presented are based on averages of the applicable total cost figures over the 1992-96 period. It can be seen that the decomposition of cost was quite similar for LG&E, Kentucky Utilities and the sample mean utility. For all, capital cost accounted for about one half and energy costs from 24 percent to 31 percent of the total cost of electric utility services. The balance of cost was divided about equally between labor services and other O&M inputs.

3. Business Condition Variables

3.1 Output Quantity Variables

As noted above, economic theory suggests that the amount of work a company performs is a relevant business condition category. Workload is a multidimensional phenomenon and therefore requires multiple variables for accurate measurement. There are two workload quantity variables in our model: the total number of customers served

Table 1

UTILITIES INCLUDED IN THE SAMPLE

Utility	1995 Electric Operating Revenues ($1000's)	1995 Total Number of Customers
Appalachian Power	1,524,788	852,596
Arizona Public Service	1,588,425	689,166
Arkansas Power & Light	1,607,175	606,872
Atlantic City Electric	945,757	471,851
Baltimore Gas & Electric	2,210,081	1,090,970
Bangor Hydro-Electric	178,340	117,139
Black Hills Power & Light	103,707	54,583
Boston Edison	1,598,571	660,895
Carolina Power & Light	2,960,029	1,077,039
Central Hudson Gas & Electric	399,901	261,884
Central Illinois Light	323,658	191,776
Central Illinois Public Servic	679,664	318,131
Central Louisiana Electric	377,071	224,299
Central Maine Power	874,679	513,107
Central Vermont Public Service	276,434	137,293
Cincinnati Gas & Electric	1,382,921	599,924
Cleveland Electric Illuminatin	1,716,744	748,022
Columbus Southern Power	1,051,397	593,364
Commonwealth Edison	6,842,088	3,368,868
Connecticut Light & Power	2,355,245	1,094,527
Consolidated Edison-NY	5,067,371	2,994,460
Consumers Power	2,248,141	1,557,501
Dayton Power & Light	1,020,333	472,526
Delmarva Power & Light	886,813	417,113
Detroit Edison	3,584,804	1,991,500
Duke Power	4,283,858	1,774,360
Duquesne Light	1,164,365	579,527
El Paso Electric	539,009	271,197
Empire District Electric	188,568	134,702
Fitchburg Gas & Electric Light	46,116	25,251
Florida Power	2,227,212	1,271,784
Florida Power & Light	5,441,221	3,488,811
Georgia Power	4,339,397	1,694,689
Green Mountain Power	157,707	81,471
Gulf Power	598,046	325,119
Gulf States Utilities	1,767,042	607,636
Houston Lighting & Power	3,527,876	1,491,139
Idaho Power	519,012	335,288
Illinois Power	1,355,305	551,843
Indiana Michigan Power	1,267,268	532,899
Indianapolis Power & Light	665,099	405,739
Interstate Power	269,711	162,686
Jersey Central Power & Light	2,021,220	934,271
Kansas City Power & Light	874,372	429,940
Kansas Gas & Electric	613,624	274,550
Kentucky Power	324,214	164,301
Kentucky Utilities	680,781	449,144
Louisiana Power & Light	1,666,930	610,527
Louisville Gas & Electric	564,060	345,025
Madison Gas & Electric	153,372	119,338
Maine Public Service	53,161	34,965
Metropolitan Edison	835,072	461,312
Minnesota Power & Light	431,713	120,557

Table 1

Utility	1995 Electric Operating Revenues ($1000's)	1995 Total Number of Customers
Mississippi Power	509,692	183,734
Mississippi Power & Light	870,433	370,253
Monongahela Power	708,684	345,433
Montana Dakota Utilities	130,986	111,855
Montana Power	486,688	269,967
Nevada Power	741,153	441,429
New Orleans Public Service	374,654	190,274
New York State Electric & Gas	1,676,963	803,138
Niagara Mohawk Power	3,172,392	1,548,384
Northern Indiana Public Servic	1,007,197	403,693
Northern States Power	1,800,479	1,211,746
Northwestern Public Service	73,127	55,152
Ohio Edison	2,149,398	946,947
Ohio Power	1,793,880	665,393
Oklahoma Gas & Electric	1,151,640	676,950
Orange & Rockland Utilities	405,761	192,970
Otter Tail Power	197,440	123,654
Pacific Gas And Electric	**7,703,073**	**4,387,054**
Pacificorp	2,545,040	1,354,415
Pennsylvania Electric	952,433	568,185
Pennsylvania Power	298,620	142,205
Pennsylvania Power & Light	2,707,412	1,220,179
Philadelphia Electric	3,703,177	1,464,250
Potomac Edison	817,874	365,453
Potomac Electric Power	1,867,460	675,544
Public Service Electric & Gas	3,943,190	1,880,562
Public Service of Colorado	1,390,446	1,092,099
Public Service of Indiana	1,219,449	642,677
Public Service of New Mexico	566,518	328,138
Public Service of Oklahoma	676,677	471,350
Rochester Gas & Electric	714,798	339,982
San Diego Gas & Electric	**1,525,440**	**1,144,414**
Savannah Electric & Power	227,780	118,281
Sierra Pacific Power	486,242	266,725
South Carolina Electric & Gas	997,424	480,568
Southern California Edison	**7,677,702**	**4,165,541**
Southern Indiana Gas & Electric	263,689	119,525
Southwestern Public Service	848,976	369,574
St Joseph Light & Power	81,101	60,726
Tampa Electric	1,108,053	495,198
Texas Utilities Electric	5,632,337	2,311,994
Toledo Edison	853,081	288,397
Tucson Electric Power	645,464	297,964
Union Electric	2,165,406	1,126,483
United Illuminating	687,341	309,605
Virginia Electric & Power	4,288,985	1,915,906
West Pennsylvania Power	1,208,577	656,352
West Texas Utilities	336,713	185,771
Wisconsin Electric Power	1,426,379	950,810
Wisconsin Power & Light	538,678	367,818
Wisconsin Public Service	485,550	357,179

Table 2

DATA SOURCES AND VARIABLE CONSTRUCTION

Cost of Labor
FERC Form 1
Total Salaries and Wages
+ Employee Pensions and Benefits

Price of Labor
FERC Form 1
Total Salaries and Wages + Pensions and Benefits
/ Number of Employees

Cost of Energy
FERC Form 1
Purchased Power Expense
+ Steam Generation Fuel Expense

Price of Energy
FERC Form 1 / UDI Utility Datapak
Utility Purchased Power Cost
Utility Purchased Power Quantity
Non-utility Purchased Power Cost
Non-utility Purchased Power Quantity
FERC Form 423
Cost of Delivered Coal
Price of Delivered Coal ($ per MMBtu)
Cost of Delivered Fuel Oil
Price of Delivered Fuel Oil ($ per MMBtu)
Cost of Delivered Natural Gas
Price of Delivered Natural Gas ($ per MMBtu)

Cost of Other O&M Inputs
FERC Form1
Total Electric Operating Expenses
- Depreciation Expense
- Federal Income Taxes
- Other Income Taxes
- Taxes Other Than Income Taxes
- Provision for Deferred Income Taxes
+ Provision for Deferred Income Taxes (credit)
- Investment Tax Credit
- Cost of Energy
- Cost of Labor

Price of Other O&M Inputs
National Income and Product Accounts; Survey of Current Business, various issues
Chain-weighted Gross Domestic Product - Price Index

Cost of Capital Services

FERC Form 1

Federal Income Taxes
\+ Other Income Taxes
\+ Taxes Other Than Income Taxes
\+ Other Capital Costs

Other Capital Costs

Quantity of Capital Services
* Price of Capital Services

Quantity of Capital Services

FERC Form 1

Total Electric Utility Plant
Accumulated Depreciation of Electric Utility Plant
Annual Capital Additions

Handy-Whitman Indexes of Public Utility Construction Costs; Whitman, Requardt and Associates

Electric Utility Construction Cost Indexes

Price of Capital Services

FERC Form 1

Total Electric Utility Plant
Accumulated Depreciation of Electric Utility Plant
Annual Capital Additions

Handy-Whitman Indexes of Public Utility Construction Costs; Whitman, Requardt and Associates

Electric Utility Construction Cost Indexes

National Income and Product Accounts; Survey of Current Business, various issues

Opportunity Cost of Capital

Means Heavy Construction Cost Data -1997; RS Means Company

City Construction Cost Index

Total Cost

Cost of Labor
\+ Cost of Energy
\+ Cost of Other O&M Inputs
\+ Cost of Capital

Total Customers

FERC Form 1

Total Number of Customers

Total Volume

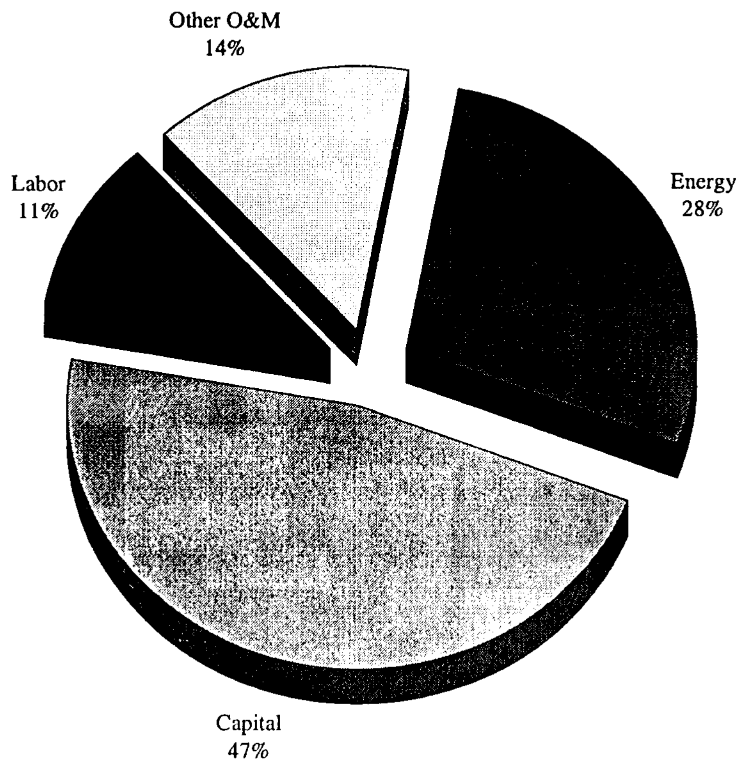
FERC Form 1

Total Sales

Figure 1

AVERAGE COMPREHENSIVE COST SHARES FOR THE SAMPLE MEAN FIRM AND LOUISVILLE GAS & ELECTRIC, 1992-1996

Sample Mean



Louisville Gas & Electric

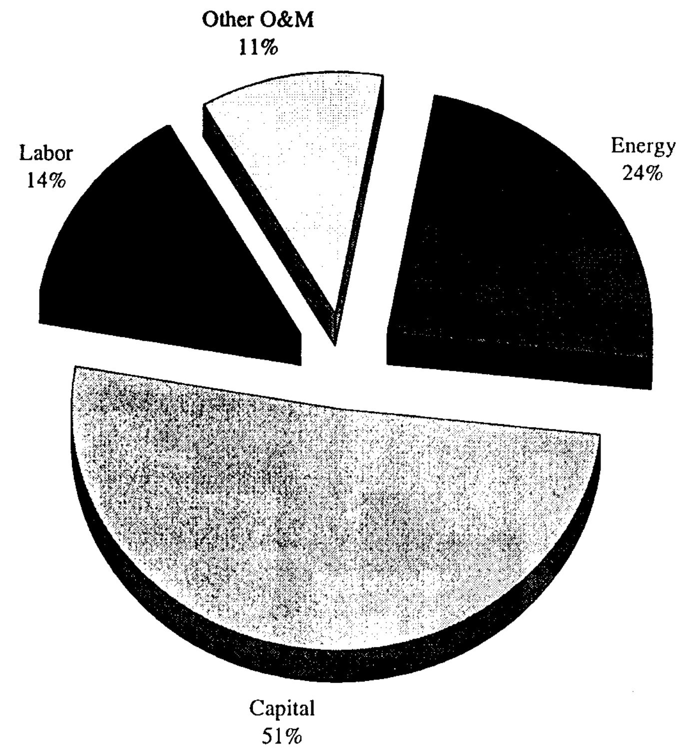
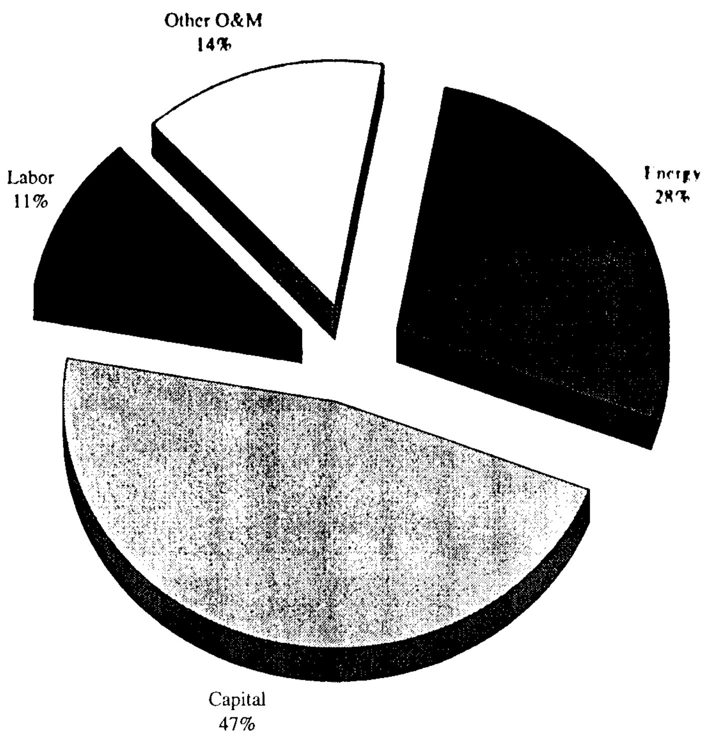


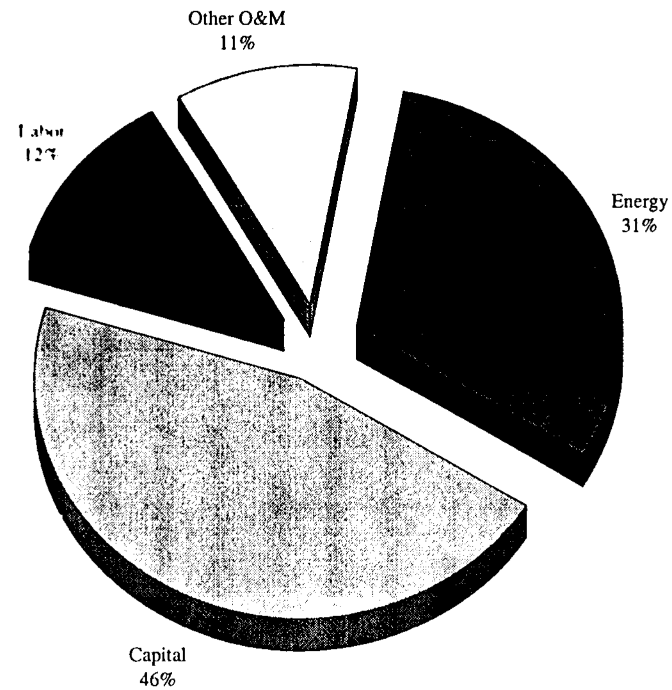
Figure 1 (continued)

AVERAGE COMPREHENSIVE COST SHARES FOR THE SAMPLE MEAN FIRM AND KENTUCKY UTILITIES, 1992-1996

Sample Mean



Kentucky Utilities



and the total sales volume measured in MWh. Data on both variables are drawn from FERC Form 1.

3.2 Input Prices

Cost theory also suggests that the prices paid for production inputs are relevant business conditions. In this model we have included input price variables for capital services, labor, energy, and other O&M inputs. The other O&M category includes materials, rentals, and outside labor services. This is often called the "materials" category. A "KLEM" (capital, labor, energy, and materials) breakdown of production inputs has been widely used in scholarly cost function research.

The computation of a capital service price is described above and detailed in the work papers. The energy price variable for each company is an index featuring five input categories: coal, residual fuel oil, natural gas, utility purchased power, and non-utility purchased power. These categories represent energy sources with distinct characteristics.

The price of labor for each company was calculated as labor cost per full-time equivalent employee. Labor cost is the sum of salaries and wages and pensions and other benefits. The requisite data for the labor prices were all drawn from FERC Form 1. Prices for other O&M inputs were assumed to be the same in a given year for all companies. They were escalated by the chain-weighted price index for gross domestic product (GDPPI).

3.3 Other Business Conditions

A binary variable was added to the model to capture any cost impact of different policy environments not otherwise covered by the model. The variable allows predicted cost to differ for utilities operating in states where utilities incur unusually large costs for demand-side management (DSM) and power purchases from unregulated generators. The states identified as having such policies were California, Connecticut, Massachusetts, Maine, New Jersey, New York, Oklahoma, Colorado, and Virginia.

3.4 Values for KU and LG&E

Table 3 compares the 1992-96 average values of electric utility cost and selected business condition variables for KU and LG&E to the corresponding averages for the sample mean utility. It can be seen that the cost incurred by each company was more than fifty percent below that incurred by the average company in the sample. The sales volumes and customer totals of the two companies were also below the mean but were typically not more than fifty percent below. The input prices of the two companies were typically below the corresponding average prices.

Table 3

AVERAGE VALUES OF VARIABLES IN THE BENCHMARK STUDY*

Variable	Units	Full Sample Average	Louisville Gas & Electric	Kentucky Utilities
Total Cost of Electric Services	Thousands of $	1,696,130	647,920	750,779
Price of Energy	Index Number	1.076	0.789	0.813
Coal	Cents per MMBtu	141.6	107.0	114.1
Fuel Oil	Cents per MMBtu	253.5	290.9	290.9
Natural Gas	Cents per MMBtu	245.8	299.0	299.0
Utility Purchased Power	$ per KWh	29.20	19.34	19.06
Non-Utility Purchased Power	$ per KWh	42.56	31.14	28.09
Price of Capital Services	Index Number	1.498	1.419	1.228
Taxes	$ per unit of capital	0.348	0.216	0.196
Other Capital Costs	$ per unit of capital	1.150	1.203	1.031
Price of Labor Services	$ per Employee	45,922	43,079	41,660
Price of Other O&M Inputs	Index Number	105.1	105.1	105.1
Total Sales Volume	Megawatthours	22,514,800	12,885,131	16,859,983
Total Retail Customers	Customers	742,650	340,108	440,788

* The sample period is 1992-1996.

Table 4

TRANSLOG COMPREHENSIVE COST FUNCTION REGRESSION RESULTS

VARIABLE KEY

PL = Price of Labor Services
PK = Price of Capital Services
PE = Price of Energy Products
PO = Price of Other O&M Inputs
V = Total Sales Volumes
N = Total Customers

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
PL	**0.105**	**40.37**
PL*PL	**0.050**	**3.46**
PL*PK	-0.009	-0.73
PL*PE	**-0.051**	**-4.56**
PL*PO	**0.010**	**0.50**
PL*V	**-0.020**	**-2.61**
PL*N	**0.021**	**2.45**
PK	**0.478**	**69.60**
PK*PK	**0.151**	**6.07**
PK*PE	**-0.225**	**-10.47**
PK*PO	**0.083**	**3.15**
PK*V	0.009	0.49
PK*N	0.018	0.89
PE	**0.275**	**30.03**
PE*PE	0.271	**9.04**
PE*PO	0.005	0.19
PE*V	0.010	0.40
PE*N	-0.036	-1.38

EXPLANATORY VARIABLE	ESTIMATED COEFFICIENT	T-STATISTIC
PO	**0.142**	**23.35**
PO*PO	**-0.098**	**-2.07**
PO*V	0.001	0.05
PO*N	-0.002	-0.12
V	**0.670**	**12.77**
V*V	-0.048	-0.34
V*N	0.007	0.06
N	**0.332**	**6.50**
N*N	0.049	0.40
Constant	**16.536**	**928.60**
Policy	**0.074**	**2.19**

BOLD denotes that the parameter estimate is significantly different from zero at a 90% level of confidence.

Table 5

BENCHMARK RESULTS : ACTUAL AND PREDICTED TOTAL COST, PERCENTAGE DIFFERENCE AND STATISTICAL SIGNIFICANCE

Utility	Actual Total Cost ($1,000s)	Predicted Total Cost ($1,000s)	Percentage Difference	T-Statistic
Louisville Gas & Electric	647,920	762,321	-16.26%	-8.73 **
Kentucky Utilities	750,779	925,109	-20.88%	-11.97 **

** Indicates significantly different from zero at a 90% level of confidence.

D. Empirical Results

1. Econometric Work

The estimates of cost model parameters obtained from our econometric work were generally quite plausible. These estimates are presented in Table 4. The cost of electric service provision was found to increase with the prices of all four production inputs. The price of an input had a larger impact on cost the larger was the input's share of total cost. For example, cost was much more sensitive to differences between companies in the capital service price than to differences in the prices of energy products or labor.

Our two workload quantity variables were also found to be important cost drivers. A company's cost was found to be higher the larger was its sales volume and number of retail customers that it served. The sensitivity of cost to differences between the delivery volumes of companies was found to be twice as great as the sensitivity to differences in customer numbers. Note also that cost was found to be significantly higher for utilities in states with unusually high expenses for DSM and power purchases from unregulated generators.

2. Cost Performance of KU and LG&E

Table 5 shows the results of our cost performance evaluation for the two companies. One result is the difference between each utility's average annual cost during the 1992-96 period and the point prediction of same made by the econometric cost model. It can be seen that average annual costs for LG&E and KU were, respectively, 16% and 21% below the model's point predictions of same. Ranking all 104 sampled utilities based on the percentage difference between actual and predicted cost, LG&E and KU ranked twelfth and fourth, respectively.

A 90% confidence interval was used to test the hypothesis that the cost incurred by each company was the same as the model's prediction. The companies' costs were below the lower bounds of the confidence intervals in both cases. Hence, we must reject the hypothesis that the companies were average cost performers during the sample period. The results suggest instead that they were significantly superior performers.

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